Major Assumptions for the Forecasts

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2003* (*AEO2003*) are generated from the National Energy Modeling System (NEMS), developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress and other offices within the Department of Energy. The *AEO* forecasts are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years into the future. In order to represent the regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and aggregations of the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production activity, and international petroleum supply availability.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, permitting the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the midterm horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of September 1, 2002, such as the Clean Air Act Amendments of 1990 (CAAA90) and the costs of compliance with other regulations.

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. In comparison with EIA's past energy data publications, the impact of the definition changes for the industrial sector is to reduce measured natural gas consumption. For example, the previously reported value for 2000 has been revised from 9.39 trillion cubic feet to 8.25 trillion cubic feet. In comparison with past energy data publications, the impact of the definition changes and new data sources for total energy use increases measured natural gas consumption. Total natural gas consumption in 2000 is 0.6 trillion cubic feet higher than was previously reported. The impact of the review on reported fuel values is discussed in "Issues in Focus," page 32. More detailed discussion is available in EIA's *Annual Energy Review 2001*, Appendix H, "Estimating and Presenting Power Sector Fuel Use in EIA Publications and Analyses," web site www.eia.doe.gov/emeu/aer/pdf/pages/sec_h.pdf.

Major Assumptions for the Forecasts

In general, the historical data used for the *AEO2003* projections were based on EIA's *Annual Energy Review 2001*, published in November 2002 [*1*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2002. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2001*, published in December 2002 [*2*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the forecasts. For example, the transportation demand sector in *AEO2003* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of all historical data.

The *AEO2003* projections for 2002 and 2003 incorporate short-term projections from EIA's September 2002 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to the monthly updates of the *STEO* [*3*].

Component modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), interest rates, disposable income, and employment. Industrial drivers are calculated for 35 industrial sectors. This module uses the following Global Insight (formerly DRI-WEFA) models: Macroeconomic Model of the U.S. Economy, National Industrial Shipments Model, National Employment Model, and Regional Model. In addition, EIA has constructed a Commercial Floorspace Model to forecast 13 floorspace types in 9 Census Divisions.

International Module

The International Module represents the world oil markets, calculating the average world oil price and computing supply curves for five categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS, in response to changes in U.S. import requirements. International petroleum product supply curves, including curves for oxygenates, are also calculated and provided to the PMM.

Household Expenditures Module

The Household Expenditures Module provides estimates of average household direct expenditures for energy used in the home and in private motor vehicle transportation. The forecasts of expenditures reflect the projections from NEMS for the residential and transportation sectors. The projected household energy expenditures incorporate the changes in residential energy prices and motor gasoline price determined in NEMS, as well as changes in the efficiency of energy use for residential end uses and in light-duty vehicle fuel efficiency. Estimates of average expenditures for households are provided by income group and Census division.

Residential and Commercial Demand Modules

The Residential Demand Module forecasts consumption of residential sector energy by housing type and end use, subject to delivered energy prices, availability of renewable sources of energy, and housing starts. The Commercial Demand Module forecasts consumption of commercial sector energy by building types and nonbuilding uses of energy and by category of end use, subject to delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction. Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and effects of both building shell and appliance standards. Both modules include a representation of distributed generation.

Industrial Demand Module

The Industrial Demand Module forecasts the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. The industries are classified into three groups—energy-intensive, non-energy-intensive, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module forecasts consumption of transportation sector fuels, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA90 and other legislative proposals, and the module includes a component to explicitly assess the penetration of alternative-fuel vehicles.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, and natural gas; costs of generation by centralized renewables; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are represented in the planning and dispatching submodules. The levelized fuel cost of uranium fuel for nuclear generation is directly incorporated into the Electricity Market Module. All CAAA90 compliance options are explicitly represented in the capacity expansion and dispatch decisions. New generating technologies for fossil fuels, nuclear, and renewables compete directly in the decisions.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing natural resource supply and technology input information for central-station, grid-connected electricity generation technologies, including biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal, solar photovoltaics, and wind energy. The RFM contains natural resource supply estimates representing the regional opportunities for renewable energy development. Conventional hydroelectricity is represented in the Electricity Market Module (EMM).

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships between the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, subject to the prices for crude oil and natural gas, the domestic recoverable resource base, and technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports, exports to Canada and Mexico, and liquefied natural gas imports and exports. Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate, domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline and storage capacity expansion requirements. Peak and off-peak periods are represented for natural gas transmission, and core and non-core markets are represented at the burner tip. Key components of pipeline and distributor tariffs are included in the pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) forecasts prices of petroleum products, crude oil and product import activity, and domestic refinery operations, including fuel consumption, subject to the demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and alcohol fuels. The module represents refining activities for three regions—Petroleum Administration for Defense District (PADD) 1, PADD 5, and an aggregate of PADDs 2, 3, and 4. The module uses the same crude oil types as the International Module. It explicitly models the requirements of CAAA90 and the costs of automotive fuels, such as oxygenated and reformulated gasoline, and includes oxygenate production and blending for reformulated gasoline. *AEO2003* reflects legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, and Washington [*4*].

Because the *AEO2003* reference case assumes current laws and regulations, it assumes that the Federal oxygen requirement for reformulated gasoline in Federal nonattainment areas will remain intact. The "Tier 2" regulation that requires the nationwide phase-in of gasoline with a greatly reduced annual average sulfur content, 30 parts per million (ppm), between 2004 and 2007 is explicitly modeled. The new "ultra-low-sulfur diesel" regulation finalized in December 2000 is also explicitly modeled. The diesel regulation requires that 80 percent of the highway diesel produced between June 1, 2006, and May 31, 2010, have a maximum sulfur content of 15 ppm, and that all highway diesel fuel meet the same limit after June 1, 2010. Costs of the regulation include capacity expansion for refinery processing units based on a 10-percent hurdle rate and a 10-percent after-tax return on investment. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs, State and Federal taxes, and environmental site costs. *AEO2003* assumes that refining capacity expansion may occur on the East Coast, West Coast, and Gulf Coast.

Coal Market Module

The Coal Market Module simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by physical characteristics, such as the heat and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, fuel costs, labor productivity, and factor input costs. Twelve coal types are represented, differentiated by coal rank, sulfur content, and mining process. Production and distribution are computed for 11 supply and 13 demand regions, using imputed coal transportation costs and trends in factor input costs. The Coal Market Module also forecasts the requirements for U.S. coal exports and imports. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. Both the domestic and international coal markets are simulated in a linear program.

Major assumptions for the *Annual Energy Outlook 2003*

Table G1 provides a summary of the cases used to derive the *AEO2003* forecasts. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed.

Assumptions for domestic macroeconomic activity are presented in the "Market Trends" section. The following section describes the key regulatory, programmatic, and resource assumptions that factor into the projections. More detailed assumptions for each sector are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

World oil market assumptions

World oil price. The world oil price is assumed to be the annual average acquisition cost of imported crude oils to U.S. refiners. The low, reference, and high price cases reflect alternative assumptions regarding the expansion of production capacity in the nations comprising the Organization of Petroleum Exporting Countries (OPEC), particularly those producers in the Persian Gulf region. The forecast of the world oil

Table G1. Summary of the *AEO2003* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Reference	Baseline economic growth, world oil price, and technology assumptions	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 51	—
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent, compared to the reference case growth of 3.0 percent.	Fully integrated	p. 51	—
Low World Oil Price	World oil prices are $19.04 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 52	—
High World Oil Price	World oil prices are $33.05 per barrel in 2025, compared to $26.57 per barrel in the reference case.	Fully integrated	p. 52	—
Residential: 2003 Technology	Future equipment purchases based on equipment available in 2003. Existing building shell efficiencies fixed at 2003 levels.	With commercial	p. 63	p. 233
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Heating shell efficiency increases by 12 percent from 1997 values by 2025.	With commercial	p. 63	p. 234
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Heating shell efficiency increases by 16 percent from 1997 values by 2025.	With commercial	p. 63	p. 234
Commercial: 2003 Technology	Future equipment purchases based on equipment available in 2003. Building shell efficiencies fixed at 2003 levels.	With residential	p. 64	p. 235
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential	p. 64	p. 235
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies increase 50 percent faster than in the reference case.	With residential	p. 64	p. 235
Industrial: 2003 Technology	Efficiency of plant and equipment fixed at 2003 levels.	Standalone	p. 65	p. 236
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment.	Standalone	p. 65	p. 236
Transportation: 2003 Technology	Efficiencies for new equipment in all modes of travel are fixed at 2003 levels.	Standalone	p. 65	p. 237
Transportation: High Technology	Reduced costs and improved efficiencies are assumed for advanced technologies.	Standalone	p. 65	p. 237
Integrated 2003 Technology	Combination of the residential, commercial, industrial, and transportation 2003 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2002 levels.	Fully integrated	p. 93	—

Table G1. Summary of the *AEO2003* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix G
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case.	Fully integrated	p. 93	—
Electricity: Advanced Nuclear Cost	New nuclear capacity is assumed to have both lower capital costs than in the reference case.	Partially integrated	p. 71	p. 240
Electricity: High Demand	Electricity demand increases at an annual rate of 2.5 percent, compared to 1.8 percent in the reference case.	Partially integrated	p. 71	p. 240
Electricity: Low Fossil Technology	New advanced fossil generating technologies are assumed not to improve over time from 2003.	Partially integrated	p. 72	p. 240
Electricity: High Fossil Technology	Costs and/or efficiencies for advanced fossil-fired generating technologies improve from reference case values.	Partially integrated	p. 72	p. 240
Renewables: High Renewables	Lower costs and higher efficiencies for central-station renewable generating technologies and for distributed photovoltaics, approximating U.S. Department of Energy goals for 2025. Includes greater improvements in residential and commercial photovoltaic systems, more rapid improvement in recovery of industrial biomass byproducts, and more rapid improvement in cellulosic ethanol production technology.	Fully integrated	p. 74	p. 242
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 15-percent slower improvement than in the reference case.	Fully integrated	p. 79, p. 81	p. 243
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 15-percent more rapid improvement than in the reference case.	Fully integrated	p. 79, p. 81	p. 243
Coal: Low Mining Cost	Productivity increases at an annual rate of 3.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs decrease by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 87	p. 247
Coal: High Mining Cost	Productivity increases at an annual rate of 0.1 percent, compared to the reference case growth of 1.6 percent. Real wages and real mine equipment costs increase by 0.5 percent annually, compared to constant real wages and equipment costs in the reference case.	Fully integrated	p. 87	p. 247

price in a given year is a function of OPEC production capacity utilization and the world oil price in the previous year. The three price cases do not assume any disruptions in petroleum supply.

World oil demand. Demand outside the United States is assumed to be for total petroleum with no specificity as to individual refined products or sectors of the economy. The forecast of petroleum demand within a region is a Koyck-lag formulation and is a function of world oil price and GDP. Estimates of regional GDPs are from EIA's *International Energy Outlook 2002*.

World oil supply. Supply outside the United States is assumed to be total liquids and includes production of crude oils (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, refinery gains, alcohol, and liquids produced from coal and other sources. The forecast of oil supply is a function of the world oil price, estimates of proved oil reserves, estimates of ultimately recoverable oil resources, and technological improvements that affect exploration, recovery, and cost. Estimates of proved oil reserves are provided by the *Oil & Gas Journal* and represent country-level assessments as of January 1, 2002. Estimates of ultimately recoverable oil resources are provided by the United States Geological Survey (USGS) and are part of its "Worldwide Petroleum Assessment 2002." Technology factors are derived from the DESTINY forecast software and are a part of the International Energy Services of Petroconsultants, Inc.

Buildings sector assumptions

The buildings sector includes both residential and commercial structures. The National Appliance Energy Conservation Act of 1987 (NAECA) and the Energy Policy Act of 1992 (EPACT), both of which are incorporated in *AEO2003*, contain provisions that affect future buildings sector energy use. The most significant are minimum equipment efficiency standards, which require that new heating, cooling, and other specified energy-using equipment meet minimum energy efficiency levels, which change over time. The manufacture of equipment that does not meet the standards is prohibited. Federal mandates, such as Executive Order 13123, "Greening the Government Through Efficient Energy Management" (signed in June 1999) and Executive Order 13221, "Energy-Efficient Standby Power Devices" (signed in July 2001), are expected to affect future energy use in Federal buildings.

Residential assumptions. The NAECA minimum standards [*5*] for the major types of equipment in the residential sector are:

- Central air conditioners and heat pumps—a 10.0 minimum seasonal energy efficiency ratio for 1992, increasing to 12.0 in 2006
- Room air conditioners—an 8.7 energy efficiency ratio in 1990, increasing to 9.7 in 2003
- Gas/oil furnaces—a 0.78 annual fuel utilization efficiency in 1992
- Refrigerators—a standard of 976 kilowatthours per year in 1990, decreasing to 691 kilowatthours per year in 1993 and to 483 kilowatthours per year in 2002
- Electric water heaters—a 0.88 energy factor in 1990, increasing to 0.90 in 2004
- Natural gas water heaters—a 0.54 energy factor in 1990, increasing to 0.59 in 2004.

The *AEO2003* version of the NEMS Residential Demand Module is based on EIA's Residential Energy Consumption Survey (RECS) [*6*]. This survey provides most of the housing stock characteristics, appliance stock information (equipment type and fuel), and energy consumption estimates used to initialize the residential module. The projected effects of equipment turnover and the choice of various levels of equipment energy efficiency are based on tradeoffs between normally higher equipment costs for the more efficient equipment versus lower annual energy costs. Equipment characterizations begin with the minimum efficiency standards that apply, recognizing the range of equipment available with even higher energy efficiency. These characterizations include equipment made available through various green programs, such as the U.S. Environmental Protection Agency (EPA) Energy Star Programs [*7*].

AEO2003 uses a combined heating, ventilation, and air conditioning (HVAC)/shell module to model building shells in new construction. The module combines specific heating and cooling equipment with appropriate levels of shell efficiency to model the least expensive ways to meet selected overall efficiency levels. The levels include:

- The current average new house
- The International Energy Conservation Code (IECC 2000)
- Energy Star Homes using upgraded HVAC equipment and/or shell integrity (combined energy requirements for HVAC must be 30 percent lower than IECC 2000)
- The PATH home (HUD and DOE's Partnership for Advancing Technology in Housing [*8*])
- A shell intermediate to Energy Star and PATH set to save 40 percent of HVAC energy.

Similar to the choice of end-use equipment, the choice of HVAC/shell efficiency level among the available alternatives is based on a tradeoff between estimated higher initial capital costs for the more efficient combinations and lower estimated annual energy costs.

In addition to the *AEO2003* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the residential sector:

- The *2003 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2003. Existing building shell efficiencies are assumed to be fixed at 2003 levels.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*9*]. Heating shell efficiency is projected to increase by 12 percent over 1997 levels by 2025.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Heating shell efficiency is projected to increase by 16 percent over 1997 levels by 2025.

Commercial assumptions. Minimum equipment efficiency standards for the commercial sector are mandated in the EPACT legislation [*10*]. Minimum standards for representative equipment types are:

- Central air conditioning heat pumps—a 9.7 seasonal energy efficiency rating (January 1994)
- Natural-gas-fired forced-air furnaces—a 0.8 annual fuel utilization efficiency standard (January 1994)
- Natural-gas-fired storage water heaters—a 0.80 thermal efficiency standard (October 2003)
- Fluorescent lamps—a 75.0 lumens per watt lighting efficacy standard for 4-foot F40T12 lamps (November 1995) and an 80.0 lumens per watt efficiency standard for 8-foot F96T12 lamps (May 1994)
- Fluorescent lamp ballasts—a standard mandating electronic ballasts with a 1.17 ballast efficacy factor for 4-foot ballasts holding two F40T12 lamps and a 0.63 ballast efficacy for 8-foot ballasts holding two F96T12 lamps (April 2005 for new lighting systems, June 2010 for replacement ballasts).

Improvements to existing building shells are based on assumed annual efficiency increases. New building shell efficiencies relative to the efficiencies of existing construction vary for each of the 11 building types. The effects of shell improvements are modeled differentially for heating and cooling. For space heating, existing and new shells improve by 5 percent and 7 percent, respectively, by 2025 relative to the 1999 averages.

Among the energy efficiency programs recognized in the *AEO2003* reference case are the expansion of the EPA Energy Star Buildings program and improvements to building shells from advanced insulation methods and technologies. The EPA green programs are designed to facilitate cost-effective retrofitting of equipment by providing participants with information and analysis as well as participation recognition. Retrofitting behavior is captured in the commercial module through discount parameters for controlling cost-based equipment retrofit decisions in various market segments. To model programs that target particular end uses, the *AEO2003* version of the commercial module includes end-use-specific segmentation of discount rates. Federal buildings are assumed to participate in energy efficiency programs and to use the 10-year Treasury Bond rate as a discount rate in making equipment purchase decisions, pursuant to the directives in Executive Order 13123.

The definition of the commercial sector for *AEO2003* is based on data from the 1999 Commercial Buildings Energy Consumption Survey (CBECS) [*11*]. Parking garages and commercial buildings on multibuilding manufacturing sites, included in the previous CBECS, were eliminated from the target building population starting with the 1995 CBECS. In addition, the CBECS data are estimates based on reported data from representatives of a randomly chosen subset of the entire population of commercial buildings. As a result, the estimates always differ from the true population values and vary from survey to survey. Differences between the estimated values and the actual population values result from both nonsampling errors that would be expected to occur in all possible samples and sampling errors that occur because the survey estimate is calculated from a randomly chosen subset of the entire population [*12*].

Due to the variability caused by nonsampling and sampling errors, the estimates of commercial floorspace for the 1999 CBECS are higher than the 1995 CBECS estimates. For example, the 1999 CBECS reports 14 percent more commercial floorspace in the United States than was reported in the 1995 CBECS. The most notable effect on *AEO2003* projections is seen in commercial energy intensity. Commercial energy use per square foot reported in *AEO2003* is significantly lower than in *AEO*s based on the 1995 CBECS, not because energy consumption is lower but because the 1999 floorspace estimates are higher. The variability between CBECS surveys also results in different estimates of the amount of each major fuel used to provide end-use services such as space heating, lighting, etc., affecting the *AEO2003* projections for fuel consumption within each end use. For example, the 1999 CBECS estimates for equipment replacement lead to lower end-use intensities for fuel used for heating and cooling than the end-use intensities based on the 1995 CBECS.

In addition to the *AEO2003* reference case, three cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of equipment and building shell efficiencies. For the commercial sector:

- The *2003 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2003. Building shell efficiencies are assumed to be fixed at 2003 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than the reference case [*13*]. Building shell efficiencies are assumed to improve at a rate that is 50 percent faster than the rate of improvement in the reference case.
- The *best available technology* case assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year in the high technology case, regardless of cost. Building shell efficiencies are assumed to improve at a 50 percent faster rate than in the reference case.

Buildings renewable energy. The forecast for wood consumption in the residential sector is based on the RECS. The RECS data provide a benchmark for British thermal units (Btu) of wood energy use in 1997. Wood consumption is then computed by multiplying the number of homes that use wood for main and secondary space heating by the amount of wood used. Ground source (geothermal) heat pump energy consumption is also based on the latest RECS; however, the measure of geothermal energy consumption is represented by the amount of primary energy displaced by using a geothermal heat pump in place of an electric resistance furnace. Residential and commercial solar thermal energy consumption for water heating is represented by displaced primary energy relative to an electric water heater. Residential and commercial solar photovoltaic systems are discussed in the distributed generation section that follows.

Buildings distributed generation. Distributed generation includes photovoltaics and fuel cells for both the residential and commercial sectors, as well as microturbines and conventional combined heat and power technologies for the commercial sector. The forecast of distributed generation is developed on the basis of economic returns projected for investments in distributed generation technologies. The model uses a detailed cash-flow approach for each technology to estimate the number of years required to achieve a cumulative positive cash flow (although some technologies may never achieve a cumulative positive cash flow). Penetration rates are estimated by Census division and building type and vary by building vintage (newly constructed versus existing floorspace).

For purchases not related to specific programs, penetration rates are determined by the number of years required for an investment to show a positive economic return: the more quickly costs are recovered, the higher the technology penetration rate. Solar photovoltaic technology specifications for the residential and commercial sectors are based on a joint U.S. Department of Energy and Electric Power Research Institute report published in December 1997. Program-driven installations of photovoltaic systems are based on information from DOE's Photovoltaic and Million Solar Roofs programs, as well as DOE and industry news releases and the National Renewable Energy Laboratory's Renewable Electric Plant Information System. The program-driven installations incorporate some of the non-economic considerations and local incentives that are not captured in the cash flow model.

The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2025 that approximate DOE's Office of Energy Efficiency and Renewable Energy technology characterizations for distributed photovoltaic technologies [*14*]. The assumptions were used in the integrated high renewables case, which focuses on electricity generation.

Industrial sector assumptions

The manufacturing portion of the Industrial Demand Module is calibrated to EIA's 1998 Manufacturing Energy Consumption Survey [*15*]. The nonmanufacturing portion of the module is based on information from EIA, the U.S. Department of Agriculture, and the U.S. Census Bureau [*16*]. EPACT sets efficiency standards for coke ovens and for boilers, furnaces, and electric motors. CAAA90 sets emissions limits for criteria air pollutants. The electric motor standards in EPACT set minimum efficiency levels for all motors up to 200 horsepower purchased after 1998 [*17*]. It has been estimated that electric motors account for about 60 percent of industrial process electricity use. For *AEO2003*, a motor stock model was developed for the Food, Bulk Chemicals, Metal-Based Durables, and Balance of Manufacturing sectors. When new motors are purchased, either an EPACT minimum efficiency motor or a premium efficiency motor is installed, depending on prevailing electricity prices. Combined heat and power (CHP), the simultaneous generation of electricity and useful steam, has been a standard practice in the industrial sector for many years. A separate model within NEMS evaluates additions to natural-gas-fired CHP, based on technical potential and prevailing electricity and natural gas prices.

High technology, 2003 technology, and high renewables cases. The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*18*]. The high technology case also assumes a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes, at 1.0 percent per year as compared with 0.2 percent per year in the reference case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, primary energy intensity falls by 1.5 percent annually in the high technology case. In the reference case, primary energy intensity falls by 1.3 percent annually between 2001 and 2025.

The *2003 technology case* holds the energy efficiency of plant and equipment constant at the 2003 level over the forecast. In this case, primary energy intensity falls by 1.1 percent annually. Because the level and composition of industrial output are the same in the reference, high technology, and 2003 technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. Both cases were run with only the Industrial Demand Module rather than as fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.

The *high renewables case* assumes the more rapid rate of improvement in the recovery of biomass byproducts from industrial processes contained in the high technology case (1.0 percent per year, as compared with 0.2 percent per year in the reference case). This assumption is incorporated in the integrated high renewables case, which focuses on electricity generation.

Transportation sector assumptions

The transportation sector accounts for two-thirds of the Nation's oil use and has been subject to regulations for many years. The Corporate Average Fuel Economy (CAFE) standards, which mandate average miles-per-gallon standards for manufacturers, continue to be widely debated. The *AEO2003* projections assume that there will be no further increase in the CAFE standards from the current 27.5 miles per gallon standard for automobiles and 20.7 miles per gallon for light trucks and sport utility vehicles. This assumption is consistent with the overall policy that only current legislation is assumed.

EPACT requires that centrally fueled light-duty fleet operators—Federal and State governments and fuel providers (e.g., natural gas and electric utilities)—purchase a minimum fraction of alternative-fuel vehicles [*19*]. The legislation requires that alternative-fuel vehicles make up 75 percent of Federal and State fleet purchases in 2002. *AEO2003* assumes that they remain at that level through 2005. The municipal and private business fleet mandates, which are proposed to begin in 2003 at 20 percent and scale up to 70 percent by 2005, are not included in *AEO2003*.

In addition to the above requirements, the sale of zero-emission vehicles (ZEVs) required by the State of California's Low Emission Vehicle Program (LEVP) are also included in the forecast. In 1998, California modified those requirements so that 60 percent of the ZEV mandate could be met by credits earned from the sales of advanced technology vehicles, depending on their degree of similarity to electric vehicles. The remaining 40 percent of the ZEV mandate was to be achieved through the sales of "true ZEVs," which include only electric and hydrogen fuel cell vehicles [*20*]. In December 2001, further modifications were enacted that maintained progress toward the 2003 goal while recognizing technology and cost limitations on ZEV product offerings. Those modifications removed ZEV sales requirements before 2003 but maintained the 2003 required sales goal of 10 percent and required a gradual increase in ZEV sales to 16 percent by 2018.

Additional sales credits were given for the sale of true ZEVs, and partial credits were allowed for advanced technology vehicles and certain alternative-fuel vehicles. The number of vehicles included in the estimation of required ZEV sales was also increased to include light-duty and medium-duty trucks. Auto manufacturers filed a Federal suit in California in 2002 arguing that the revisions to the ZEV program are preempted by the Federal fuel economy statute of the Energy Policy and Conservation Act of 1975. In June 2002, a Federal judge granted a preliminary injunction preventing the California Air Resources Board from enforcing the ZEV regulations for model year 2003 and 2004 vehicles. The projections currently assume that California, Massachusetts, New York, Maine, and Vermont will formally begin implementing the LEVP mandates in 2005.

Technology choice. Conventional light-duty vehicle technologies are chosen by consumers and penetrate the market based on the assumption of cost-effectiveness, which compares the capital cost to the discounted stream of fuel savings from the technology. There are approximately 63 fuel-saving technologies, which vary by capital cost, date of availability, marginal fuel efficiency improvement, and marginal horsepower effect [*21*]. The projections assume that the regulations for alternative-fuel and advanced technology vehicles represent minimum requirements for alternative-fuel vehicle sales; in the model, consumers are allowed to purchase more of the vehicles if their cost, fuel efficiency, range, and performance characteristics make them desirable. Technology choice captures the manufacturers' response to the market.

Consumers do not place a significant value on high-efficiency vehicles. This is reflected in the model by assuming a 3-year payback period, with the real discount rate remaining steady at 30 percent. Expected future fuel prices are calculated based on extrapolation of the growth rate between a 5-year moving average of fuel prices 3 years and 4 years before the present year. This assumption is based on a lead time of 3 to 4 years for significant modification of the vehicles offered by a manufacturer.

For freight trucks, technology choice is based on several technology characteristics, including capital cost, marginal improvement in fuel efficiency, payback period, and discount rate, which are used to calculate a fuel price at which the technologies become cost-effective [*22*]. When technologies are mutually exclusive, the more cost-effective technology will gain market share relative to the less cost-effective technology. Efficiency improvements for both rail and ship are based on recent historical trends [*23*].

Similar to freight trucks, fuel efficiency improvements for new aircraft are also determined by a trigger fuel price, the time the technology becomes commercially available, and the projected marginal fuel efficiency improvement. The advanced technologies are ultra-high bypass, propfan, thermodynamics, hybrid laminar flow, advanced aerodynamics, and weight-reducing materials [*24*].

Travel. Projections for both personal travel [*25*] and freight travel [*26*] are based on the assumption that modal shares (for example, personal automobile travel versus mass transit) remain stable over the forecast and follow recent historical patterns. Important factors affecting the forecast of vehicle-miles traveled for light-duty vehicles are personal disposable income per capita; the ratio of miles driven by females to males in the total driving population, which increases from 56 percent in 1990 to 68 percent by 2020 and remains constant thereafter; and the cost of driving.

Travel by freight truck, rail, and ship is based on the growth in industrial output by sector and the historical relationship between freight travel and industrial output [*27*]. Both rail and ship travel are also based on projected coal production and distribution. Air travel is estimated for domestic travel (both personal and business), international travel, and dedicated air freight shipments by U.S. carriers. Depending on the market segment, the demand for air travel is based on projected disposable personal income, GDP, merchandise exports, and ticket price as a function of jet fuel prices. Load factors, which represent the percentage of seats occupied per plane and are used to convert air travel (expressed in revenue-passenger miles and revenue-ton miles) to seat-miles of demand, remain relatively constant over the forecast period.

2003 technology case. The *2003 technology case* assumes that new fuel efficiency levels are held constant at 2003 levels through the forecast horizon for all modes of travel.

High technology case. For the *high technology case*, light-duty conventional and alternative-fuel vehicle characteristics reflect more optimistic assumptions for incremental fuel economy improvements, technology introduction dates, and costs [*28*]. In the air travel sector, the high technology case assumes 40-percent efficiency improvement from new aircraft technologies by 2025. Based on an analysis by the Federal Aviation Administration, the high technology case also assumes an additional 5-percent fleet efficiency improvement from the Air Traffic Management program. In the freight truck sector, the high technology case assumes more optimistic incremental fuel efficiency improvements for engine and emission control technologies [*29*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices.

Electricity assumptions

Characteristics of generating technologies. The costs and performance of new generating technologies are important factors in determining the future mix of capacity. Fossil fuel, renewable, and nuclear technologies are represented and include those currently available as well as those that are expected to be commercially available within the horizon of the forecast. Capital cost estimates and operational characteristics, such as efficiency of electricity production, are used for decisionmaking. It is assumed that the selection of new plants to be built is based on least cost, subject to environmental constraints. The incremental costs associated with each option are evaluated and used as the basis for selecting plants to be built. Details about each of the generating plant options are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Regulation of electricity markets. It is assumed that electricity producers comply with CAAA90, which mandates a limit of 8.95 million short tons of sulfur dioxide emissions per year by 2010. Utilities are assumed to comply with the limits on sulfur dioxide emissions by retrofitting units with flue gas desulfurization (FGD) equipment, transferring or purchasing sulfur emission allowances, operating high-sulfur coal units at a lower capacity utilization rate, or switching to low-sulfur fuels. The assumed cost for FGD equipment averages approximately $440 per kilowatt, in 2001 dollars, for units of all sizes. This includes some very small, possibly uneconomical, units. The average cost for large units (500 megawatts capacity or larger) is $182 per kilowatt, although there are wide variations across the regions. It is also assumed that the market for trading emissions allowances is allowed to operate without regulation and that the States do not further regulate the selection of coal to be used.

In *AEO2003*, emissions of sulfur dioxide (SO_2) from electricity generators are subject to a cap, as specified by CAAA90, which amounts to 9.48 million tons for the years 2001 through 2009 and 8.95 million tons per year thereafter. In the reference, high and low economic growth, and high and low world oil price cases, generators are projected to meet the annual SO_2 caps based solely on additions of 23 gigawatts of planned retrofits of flue gas desulfurization equipment (scrubbers) at existing coal-fired power plants, combined with the drawdown of banked SO_2 emission allowances amounting to 10.4 million tons at the end of 2000. Announced retrofits of scrubbers by Duke Power and Progress Energy in response to North Carolina's Clean Smokestacks Bill account for nearly one-half of the planned retrofits included. The remainder are based on other factors, including compliance strategies developed by generators in response to CAAA90, agreements that generators have reached with the U.S. Department of Justice in lawsuits related to New Source Review, and other State and local environmental issues.

The EPA has issued rules to limit emissions of nitrogen oxides, specifically calling for capping emissions during the summer season in 22 eastern and midwestern States. After an initial challenge, the rules have been upheld, and emissions limits have been finalized for 19 States, starting in 2004. In *AEO2003*, electricity generators in those 19 States must comply with the limits either by reducing their own emissions or by purchasing allowances from others.

The reference case assumes a transition to full competitive pricing in New York, New England, the Mid-Atlantic Area Council, and Texas. In addition, electricity prices in the East Central Area Reliability Council, the Mid-America Interconnected Network, the Southwest Power Pool, and the Rocky Mountain Power Area/Arizona (Arizona, New Mexico, Colorado, and eastern Wyoming) regions are assumed to be partially competitive. Some of the States in each of these regions have not taken action to deregulate their pricing of electricity, and in those States prices are assumed to continue to be based on traditional cost-of-service pricing. In California, a return to complete cost-of-service regulation is now assumed.

In many deregulated States the legislation has mandated price freezes or reductions over a specified transition period. *AEO2003* includes such agreements in the electricity price forecast. In general, the transition period is assumed to be a 10-year period from the beginning of restructuring in each region, during which prices gradually shift to competitive prices. The transition period reflects the time needed for the establishment of competitive market institutions and recovery of stranded costs as permitted by regulators. *AEO2003* assumes that the competitive price in deregulated regions is the marginal cost of generation.

Competitive cost of capital. The cost of capital is calculated as a weighted average of the costs of debt and equity. *AEO2003* assumes a ratio of 55 percent debt and 45 percent equity. The yield on debt represents that of a BBB corporate bond, and the cost of equity is calculated to be representative of unregulated industries similar to the electricity generation sector. It is assumed that the capital invested in a new plant must be recovered over a 20-year plant life rather than the traditional 30-year life.

Representation of utility Climate Challenge participation agreements. As a result of the Climate Challenge Program, many utilities have announced efforts to reduce their greenhouse gas emissions voluntarily. These efforts cover a wide variety of programs, including increasing demand-side management investments, repowering (fuel-switching) fossil plants, restarting nuclear plants that have been out of service, planting trees, and purchasing emissions offsets from international sources.

To the degree possible, each of the participation agreements was examined to determine whether the commitments made were addressed in the normal reference case assumptions or whether they should be addressed separately. Programs such as tree planting and emissions offset purchasing are not addressed, but the other programs are, for the most part, captured in *AEO2003*. For example, utilities annually report to EIA their plans (over the next 10 years) to bring a plant back on line, repower a plant, extend a plant's life, cancel a previously planned plant, build a new plant, or switch fuel at a plant. Data for these programs are included in the *AEO2003* input data. However, because many of the agreements do not identify the specific plants where action is planned, it is not possible to determine which of the specified actions, together with their greenhouse gas emissions savings, should be attributed to the Climate Challenge Program and which are the result of normal business operations.

Fossil steam and nuclear plant retirement assumptions. Fossil steam plants and nuclear plants are retired when it is no longer economical to run them. In each forecast year the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. If the revenue a plant receives is not sufficient to cover its forward costs (including fuel, operations and maintenance costs, and assumed annual capital additions) the plant is retired. Beyond age 30, the forward costs also include capital expenditures assumed to be needed to address aging-related issues. For fossil plants the aging-related costs are assumed to be $5 per kilowatt. For nuclear plants the aging-related costs are assumed to be $50 per kilowatt. Aging-related cost increases result from increased capital costs, decreases in performance, and/or increased maintenance expenditures to mitigate the effects of aging.

Nuclear power. There are no nuclear units actively under construction in the United States. In NEMS, new nuclear plants are competed against other options when new capacity is needed. The cost assumptions for new nuclear units are based on an analysis of recent cost estimates for nuclear designs available in the United States and worldwide.

The capital cost assumptions in the reference case are meant to represent the expense of building a new single-unit nuclear plant of approximately 1,000 megawatts at a new "greenfield" site. Because no new nuclear plants have been built in the United States in many years, there is a great deal of uncertainty about the true costs of a new unit. EIA accounts for that uncertainty by requiring that the capital cost estimates be symmetric in the sense that there is an equal probability that they could turn out to be either "too high" or "too low." For that reason, the estimate used for *AEO2003* is basically an average of the ones reviewed from various sources.

The average nuclear capacity factor in 2001 was 89 percent, the highest annual average ever in the United States. The average annual capacity factor generally increases throughout the forecast, reaching a national average of 92 percent by 2010. Capacity factor assumptions are developed at the unit level, and improvements or decrements are based on the age of the reactor.

AEO2003 assumes that the Browns Ferry 1 nuclear unit will return to operation in 2007. The unit has been shut down since 1985 for safety issues but has retained an operating license. The Tennessee Valley Authority, owner and operator of the Browns Ferry plant, recently decided to make the investment required to return the plant to service, which is expected to take 5 years. The *AEO2003* nuclear power forecast also assumes capacity increases at existing units. The U.S. Nuclear Regulatory Commission (NRC) approved 22 applications for power uprates in 2001, and another 22 were approved or pending in 2002. *AEO2003* assumes that all of those uprates will be implemented, as well as others expected by the NRC over the next 10 years, for a capacity increase of 4.2 gigawatts between 2002 and 2025.

For nuclear power plants, *an advanced nuclear cost case* analyzes the sensitivity of the projections to lower costs for new plants. The cost assumptions for the advanced nuclear cost case are consistent with goals endorsed by DOE's Office of Nuclear Energy and indicated as requirements for cost-competitiveness by the Office's Near-Term Deployment Working Group. The overnight capital cost of a new advanced nuclear unit is assumed to be $1,500 per kilowatt initially, declining to $1,200 per kilowatt by 2020 (in year 2001 dollars) and remaining constant thereafter—28 percent lower initially than assumed in the reference case and 36 percent lower in 2025. Cost and performance characteristics for all other technologies are as assumed in the reference case.

Biomass co-firing. Coal-fired power plants are allowed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure ranges from about $100 to $230 per kilowatt of biomass capacity, depending on the type and size of the boiler. A coal-fired unit modified to allow co-firing can generate up to 15 percent of its total output using biomass fuel, assuming sufficient fuel supplies are available. Larger units are required to pay additional transportation costs as the level of co-firing increases, due to the concentrated use of the regional biomass supply.

Distributed generation. *AEO2003* assumes the availability of two generic technologies for distributed electricity generation. To determine the levels of capacity and generation for distributed technologies projected to be used in the forecast, the model compares their costs with the "avoided costs" of electricity producers. The avoided costs are the costs electricity producers would incur if they added the least expensive conventional central-station generators rather than distributed generators, as well as the costs of additional transmission and distribution equipment that would be required if the distributed generators were not added. Because there are currently no reliable estimates of the transmission and distribution costs that can be avoided by adding distributed generators, regional estimates were developed for the transmission and distribution investments that would be needed for each kilowatt of central-station generating capacity added. It was then assumed that 75 percent of such "growth-related" transmission and distribution costs could be avoided by adding distributed generators.

International learning. Capital costs for all new fossil-fueled electricity generating technologies are assumed to decrease in response to foreign as well as domestic experience, to the extent that the new plants reflect technologies and firms competing in the United States. In its learning function, *AEO2003* includes 1,928 megawatts of advanced coal gasification combined-cycle capacity (including the 127-megawatt Fife plant that entered service in Scotland in 2001) and 5,244 megawatts of advanced combined-cycle natural gas capacity operating or under construction outside the United States from 2001 through 2003.

High electricity demand case. The *high electricity demand case* assumes that the demand for electricity grows by 2.5 percent annually between 2001 and 2025, compared with 1.8 percent in the reference case. No attempt was made to determine changes in the end-use sectors that would result in the stronger demand growth. The high electricity demand case is partially integrated, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. Rapid growth in electricity demand also leads to higher prices. The price of electricity in 2025 is 7.0 cents per kilowatthour in the high demand case, as compared with 6.7 cents in the reference case. Higher fuel prices, especially for natural gas, are the key factor leading to higher electricity prices.

High and low fossil technology cases. The high and low fossil technology cases are partially integrated cases, with no feedback from the Macroeconomic Activity, International, or end-use demand modules. In the *high fossil technology case*, capital costs and/or heat rates for the advanced coal and gas technologies are assumed to be lower and decline faster than in the reference case. The capital costs and heat rates for renewable, nuclear, and other fossil technologies are assumed to be the same as in the reference case. The values used in the high fossil technology case for capital costs and heat rates were based on the Vision 21 program for new generating technologies, developed by DOE's Office of Fossil Energy. In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the forecast period and remain fixed at the 2002 values assumed in the reference case. Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in these assumptions are described in the detailed assumptions, which are available on the Internet at web site www.eia.doe.gov/oiaf/aeo/assumption/.

Renewable fuels assumptions

Energy Policy Act of 1992. The EPACT 10-year renewable electricity production tax credit (PTC) of 1.5 cents per kilowatthour (now adjusted for inflation to 1.8 cents) for new wind and some biomass plants originally expired on June 30, 1999. It was first extended through December 31, 2001, and then retroactively extended from December 31, 2001 through December 31, 2003, by the Job Creation and Worker Assistance Act of 2002 (P.L. 107-147). *AEO2003* applies the credit to all wind plants built through 2003 but assumes the "closed loop" biomass plants eligible for the credit cannot be built until 2010.

Because the PTC displaces taxable income (project revenue) with non-taxable income (a tax credit), its actual value to the project owner is somewhat larger than the face value of the credit. Specifically, the 1.8-cent credit has a value of 2.8 cents, based on the assumed marginal income tax rate of 36 percent used to determine project revenue requirements for generating capacity expansion (that is, the actual value is equal to the face value divided by one minus the tax rate). This represents the additional taxable revenue the owner would have to derive from a project to compensate for the tax credit if it were not available. *AEO2003* does not project planned new wind units after 2003 for which construction is contingent on further extension of the PTC [*30*]. *AEO2003* assumes that the 10-percent investment tax credit for solar and geothermal technologies that generate electric power will be continued through 2025.

Renewable capacity additions. AEO2003 includes 6,680 megawatts of new central-station generating capacity using renewable resources, as announced by utilities and independent power producers or identified by EIA to be built from 2002 through 2020. No builds were identified after 2020. Of the total, 5,206 megawatts results from State mandates, State renewable portfolio standards (RPS), State goals, and other requirements, and 1,474 megawatts results from commercial builds and voluntary programs, such as green power programs and utility testing and demonstration projects using renewables.

For a number of reasons, *AEO2003* does not estimate all new renewable capacity implied by State RPS and other mandates; it includes only the requirement-induced capacity (generally, near term) about which the States and utilities are relatively certain. First, actual implementation for some States is proceeding more slowly than initially expected, suggesting caution in expectations for the near term. Further, States and utilities are sometimes unable to quantify new capacity that they expect to result from the RPS. Moreover, RPS implementation itself is often uncertain, given legal alternatives (such as fines and exemptions) and technology choices (such as conservation). Finally, even if the new capacity is eventually built, the technologies chosen, the year built, and the size and location are unclear.

Estimating supplemental additions of new renewable capacity for *AEO2003* is further complicated by reported transmission constraints thwarting wind development, by uncertainty about post-2003 extension of the PTC, by uncertain financial positions of utilities in the West that serve California markets, by uncertain demand for renewables in light of potential overbuilding of natural gas capacity, and by uncertainty about States' adherence to RPS mandates when economic growth is slow. As a result, the State RPS estimates should be considered relatively certain estimates of new capacity likely to be built in the near term and not as measures of the full potential consequences of the RPS over the entire forecast period.

Using publicly available information and working with State agencies, EIA confirms projections of mandated renewable energy capacity; however, limited resources preclude confirming the status of every new renewable energy plant.

The projection also includes minimum expectations for new central-station solar energy capacity assumed to be installed for reasons other than least-cost electricity supply. *AEO2003* estimates include 75.5 megawatts of central-station solar thermal-electric and 332.5 megawatts of central-station photovoltaic (PV) generating capacity to be installed from 2003 through 2025.

Renewable resources. Although conventional hydroelectricity is the largest source of renewable energy in U.S. electricity markets today, the lack of available new sites, environmental and other restrictions, and costs are assumed to halt the expansion of U.S. hydroelectric power. Solar, wind, and geothermal resources are theoretically very large, but economically accessible resources are much less available.

Solar energy (direct normal insolation) for thermal applications is considered economical only in drier regions west of the Mississippi River. Photovoltaics can be economical in all regions, although conditions are also superior in the West. Wind energy resource potential, while large, is constrained by wind quality differences, distance from markets, power transmission costs, alternative land uses, and environmental objections. The geographic distribution of available wind resources is based on work by the Pacific Northwest Laboratory [*31*], enumerating winds among average annual wind-power classes. Geothermal energy is limited geographically to regions in the western United States with hydrothermal resources of hot water and steam. Although the potential for biomass is large, transportation costs limit the amount of the resource that is economically productive, because biomass fuels have a low Btu content per weight of fuel.

The *AEO2003* reference case incorporates upward-sloping supply curves for geothermal and wind technologies, in recognition of the higher costs of consuming increasing proportions of a region's resources. Capital costs are assumed to increase in response to (1) declining natural resource quality, such as rough or steep terrain or turbulent winds, (2) increasing costs of upgrading the existing transmission and distribution network, and (3) market conditions that increase wind power costs in competition with other land uses, such as for crops, recreation, or environmental or cultural preferences.

AEO2003 includes two revisions to the treatment of wind energy for capacity planning and dispatch. The first reflects the current trend in wind capacity markets toward level capital costs and improving capacity factors, resulting from the experience gained with increasing wind turbine builds. The second change reflects the additional costs imposed on the power grid by increasing levels of wind penetration. For *AEO2003*, the marginal capacity credit for wind decreases toward zero with increasing penetration, which ensures the availability of adequate firm capacity within a region to satisfy reliability requirements. Regional penetration of wind is limited to 20 percent, to reflect additional costs of very high penetration, such as the forced shutdown of wind resources during periods of potential excess generation.

High renewables case. For the *high renewables case*, greater improvements are assumed for central-station nonhydroelectric generating technologies using renewable resources (other than landfill gas) than in the reference case, including capital costs falling below reference case estimates, in order to approximate DOE's Office of Energy Efficiency and Renewable Energy December 1997 *Renewable Energy Technology Characterizations* [*32*]. The high renewables case also incorporates reduced operations and maintenance costs, improvements in capacity factors for wind technologies, and increased biomass supplies, as well as lower capital costs for residential and commercial distributed photovoltaic systems.

Because of the nature of geothermal sites, which require incremental development to assure that the resource is viable, annual limits are placed on development. The annual limits on builds at geothermal sites were raised from 25 megawatts per year through 2015 to 50 megawatts per year for all forecast years in *AEO2003*. Other generating technologies and forecast assumptions remain unchanged from those in the reference case. The rate of improvement in the recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed in the high renewables case, and cellulosic ethanol production is assumed to capture a higher share of the renewable transportation fuels market (using the Blackman market share equation), resulting in increased cellulosic ethanol supply compared with the reference case.

Integrated technology cases. The *integrated high technology case* uses the same assumptions as the high renewables case for central-station renewable energy technologies. The *integrated low technology case* assumes that capital costs for biomass, geothermal, wind, solar thermal, and central-station photovoltaic technologies remain fixed at 2002 values, and that the capacity factors for wind turbines in each wind class remain fixed at 2002 levels.

Oil and gas supply assumptions

Domestic oil and gas technically recoverable resources. The levels of available oil and gas resources assumed for *AEO2003* are based on estimates of the technically recoverable resource base from the U.S. Geological Survey (USGS), the Minerals Management Service (MMS) of the Department of the Interior [*33*], and the National Petroleum Council (NPC), with supplemental adjustments to the USGS nonconventional resources by Advanced Resources International (ARI), an independent consulting firm.

Technological improvements affecting recovery and costs. Productivity improvements are simulated by assuming that drilling, success rates, and finding rates will improve and the effective cost of supply activities will be reduced. The assumed increase in recovery is due to the development and deployment of new technologies, such as three-dimensional seismology and horizontal drilling and completion techniques.

Drilling, operating, and lease equipment costs are expected to decline due to technological progress, at econometrically estimated rates that vary somewhat by cost and fuel categories, ranging roughly from 0.5 percent to 2.0 percent. The technological impacts work against increases in costs associated with drilling to greater depths, higher drilling activity levels, and rig availability. Success rates are assumed to improve by 0.67 to 2.62 percent per year, and finding rates are expected to improve by 0.3 to 3.5 percent per year because of technological progress.

Rapid and slow technology cases. Two alternative cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. To create these cases, conventional oil and natural gas reference case parameters for the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates were adjusted by plus or minus 15 percent. For unconventional gas, a number of key exploration and production technologies were also adjusted by plus or minus 15 percent in the rapid and slow technology cases. Key Canadian supply parameters were adjusted to simulate the assumed impacts of rapid and slow oil and gas technology penetration on Canadian supply potential.

All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of liquefied natural gas and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2003*, which is available on the Internet at www.eia.doe.gov/oiaf/aeo/assumption/.

Leasing and drilling restrictions. The projections of crude oil and natural gas supply assume that current restrictions on leasing and drilling will continue to be enforced throughout the forecast period. At present, drilling is prohibited along the entire East Coast, the west coast of Florida, and the West Coast except for the area off Southern California. In Alaska, drilling is prohibited in a number of areas, including the Arctic National Wildlife Refuge. The projections also assume that coastal drilling activities will be reduced in response to the restrictions of CAAA90, which require that offshore drilling sites within 25 miles of the coast, with the exception of areas off Texas, Louisiana, Mississippi, and Alabama, meet the same clean air requirements as onshore drilling sites.

Gas supply from Alaska, MacKenzie Delta, and LNG imports. Due to relative economics, the assumption in the model is that a pipeline from the MacKenzie Delta to Alberta would be constructed first, followed by one from Alaska, with potential expansions following thereafter. The timing of both systems is based on estimates of the cost to bring the gas to market in the United States, relative to the average lower 48 wellhead price.

A natural gas pipeline from Alaska into Alberta, Canada, is assumed to carry an initial capitalization of $11.6 billion (2002 dollars) and be depreciated over 15 years. The corresponding cost for a pipeline from the MacKenzie Delta into Alberta is $3.6 billion. It is assumed that the pipeline will require 4 years to construct (3 years for the MacKenzie pipeline), will not be completed before 2009 (2007 for MacKenzie), will deliver 4.5 billion cubic feet per day once fully operational (1.5 billion for MacKenzie), and can be expanded by 23 percent, if economical. The wellhead price of natural gas from Alaska to be delivered through the pipeline is assumed to be $0.80 per thousand cubic feet in 2001 dollars ($1.00 for MacKenzie). Gas treatment and pipeline fuel costs are accounted for as well. A capital cost risk and market price risk premium totaling $0.56 per thousand cubic feet is assumed ($0.39 for MacKenzie), above and beyond the expected cost of delivery into Alberta and on to the lower 48 States. The resulting assumption is that an average price in the lower 48 States of around $3.50 (2001 dollars) per thousand cubic feet ($3.40 for MacKenzie) would need to be maintained on average over 3 years for construction to commence. An additional $0.08 per thousand cubic feet is assumed to be necessary for an expansion of either pipeline. Expansion of the MacKenzie Delta pipeline is assumed not to occur until the Alaska pipeline is built, and only then is the Alaska pipeline allowed to expand.

The liquefied natural gas (LNG) facilities at Everett, Massachusetts, Lake Charles, Louisiana, and Elba Island, Georgia (the only ones currently in operation) have a combined design capacity of 1,880 million cubic feet per day (687 billion cubic feet per year) and an assumed combined sustainable sendout of 487 billion cubic feet per year. The LNG facility at Cove Point, Maryland, with an assumed sustainable capacity of 292 billion cubic feet per year, is assumed to reopen in 2003. This, plus additional capacity of 396 billion cubic feet per year resulting from currently proposed expansions at the four facilities, brings the total U.S. sendout capacity to 1,175 billion cubic feet per year. An assumed maximum load factor of 90 percent effectively reduces the total available LNG from existing and proposed capacity to 1,057 billion cubic feet per year. This level of LNG is viable between 2005 and 2010, when regional prices at the tailgate range from $3.31 to $3.51 per thousand cubic feet.

Existing facilities are allowed to expand beyond what has been proposed if prices make it economical. Expansions could increase available LNG from existing terminals up to an assumed level of 1,470 billion cubic feet per year. The model also has a provision for the construction of new facilities in all U.S. coastal regions and in Baja California, Mexico, once existing facilities have expanded to their assumed limits. Construction in a region is triggered when the regional price of natural gas meets or exceeds the cost (per thousand cubic feet) of producing, liquefying, transporting, and regasifying the LNG (based on the cost of a new terminal in the region). Regional prices at the LNG tailgate, including relevant transportation charges, that trigger construction range from $3.72 to $4.53 per thousand cubic feet. An LNG facility in Baja California, Mexico, with expansion potential, is assumed to be constructed at a tailgate price of $3.40 per thousand cubic feet. This contributes to the shift of Mexico from being a net importer of U.S. natural gas to a net exporter by the end of the forecast.

Natural gas transmission and distribution assumptions. Transportation rates for pipeline services are calculated with the assumption that the costs of new pipeline capacity will be rolled into the existing ratebase. The rates based on cost of service are adjusted according to pipeline utilization, to reflect a more market-based approach. In determining interstate pipeline tariffs, potential future expenditures for pipeline safety necessary to comply with the pending Pipeline Safety Improvement Act of 2002 are not considered.

Distribution markups to core customers (not including electricity generators) change over the forecast in response to changes in consumption levels and in the costs of capital and labor. Markups to electricity generators are a direct function of changes in consumption levels alone. The vehicle natural gas (VNG) sector is divided into fleet and non-fleet vehicles. The distributor tariffs for natural gas to fleet vehicles are based on historical differences between end-use and citygate prices from EIA's *Natural Gas Annual* plus Federal and State taxes on vehicle natural gas. The price to non-fleet vehicles is based on the industrial sector firm price plus an assumed dispensing charge of $3 per thousand cubic feet (1987 dollars) plus taxes.

Petroleum market assumptions

The petroleum refining and marketing industry is assumed to incur environmental costs to comply with CAAA90 and other regulations. Investments related to reducing emissions at refineries are represented as an average annualized expenditure. Costs identified by the National Petroleum Council [*34*] are allocated among the prices of liquefied petroleum gases, gasoline, distillate, and jet fuel, assuming that they are recovered in the prices of light products. The lighter products, such as gasoline and distillate, are assumed to bear a greater share of the costs, because demand for light products is less price-responsive than that for the heavier products.

Petroleum product prices also include additional costs resulting from requirements for cleaner burning gasoline and diesel fuels. The recent regulation requiring a reduction in gasoline sulfur content to an annual average of 30 ppm between 2004 and 2007 is also reflected. The additional costs are determined in the representation of refinery operations by incorporating specifications and demands for the fuels.

Demands for conventional, reformulated, and oxygenated gasolines are disaggregated from composite gasoline consumption on the basis of their 2002 market shares in each Census division. The expected market shares for oxygenated gasoline assume continued wintertime participation of carbon monoxide nonattainment areas and State-wide participation in Minnesota. Oxygenated gasoline represents about 4 percent of gasoline demand in the forecast.

Fuel ethanol production is modeled in the Petroleum Market Module (PMM). Ethanol is produced in dedicated plants from corn or cellulose feedstocks. Most ethanol is produced from corn in the Midwest (Census Divisions 3 and 4). Commercial cellulosic ethanol production from corn stover is assumed in the Midwest. Cellulosic ethanol production from wood products is assumed in the Mid-Atlantic (Census Division 2), East North Central (Census Division 3), West North Central (Census Division 4), West South Central (Census Division 7), and Pacific (Census Division 9). Ethanol is blended into gasoline at up to 10 percent by volume to provide oxygen, octane, and gasoline volume. Blended with 15 percent gasoline, it is sold as E85. Ethanol can also be used to make ethyl tertiary butyl ether (ETBE), another potential gasoline oxygenate. The PMM is capable of modeling ETBE, but it is expected to cause water contamination problems similar to those caused by MTBE and is therefore not in widespread use.

Reformulated gasoline (RFG) is assumed to continue to be consumed in the 10 serious ozone nonattainment areas required by CAAA90 and in areas that voluntarily opted into the program [*35*]. RFG projections also reflect a State-wide requirement in California and RFG required by State law in Phoenix, Arizona. In total, RFG is assumed to account for about 34 percent of annual gasoline sales throughout the *AEO2003* forecast.

RFG reflects the "Complex Model" definition as required by the EPA and the tighter Phase 2 requirements beginning in 2000. The RFG specifications used for the West Coast reflect the California Air Resources Board (CARB) State-wide gasoline requirements, first implemented in 1996, which will be tightened in 2004. The *AEO2003* projections also reflect legislation in 17 States, including California, that would restrict or ban the use of MTBE in gasoline around 2004 [*36*]. The EPA recently denied a request by California to waive the Federal oxygen requirement in Federal nonattainment areas, including Los Angeles, San Diego, Sacramento, and San Joaquin Valley. Because those areas make up about 80 percent of California's population, *AEO2003* assumes that 80 percent of RFG in the State will continue to require 2.0 percent oxygen by weight after MTBE is banned.

AEO2003 reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased down to 30 ppm between 2004 and 2007. *AEO2003* assumes that RFG has an average annual sulfur content of 135 ppm in 2001 and will meet the 30-ppm requirement in 2004. The reduction in sulfur content between 2001 and 2004 is assumed to reflect incentives for "early reduction." The regional assumptions for phasing down the sulfur content of conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30-ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

AEO2003 also incorporates the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000. By definition, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump. The new regulation contains the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100-percent requirement for ULSD thereafter. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007, and the impact of the 100-percent requirement cannot be seen until 2011. Major assumptions related to the implementation of the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7 ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process.

- The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the onset of the program, declining to 4.4 percent at full implementation. The decline reflects an expectation that, with experience, the distribution system will become more efficient at handling ULSD.

- Demand for highway-grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total demand for distillate in the transportation sector. Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.
- ULSD production is modeled through improved distillate hydrotreating units as well as the Phillips S-Zorb process. Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing two-thirds of highway diesel production; the remaining refineries will build new units. The capital cost of a revamp is assumed to be 50 percent of the cost of adding a new unit.
- No change in the sulfur level of non-road diesel is assumed, because the EPA has not yet promulgated non-road diesel standards.

If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,500 per barrel of daily capacity (2001 dollars). Operating costs are assumed to be $3.99 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.75 to $4.45 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feed is assumed to cost $0.82 per thousand cubic feet (2001 dollars).

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons of bituminous coal per day, with a production capacity of 33,200 barrels of synthetic fuels per day and 696 megawatts of capacity for electricity cogeneration sold to the grid [*37*]. CTL facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility, because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and liquefied petroleum gases. Petroleum products from CTL facilities are assumed to be competitive when distillate prices rise above the cost of CTL production (adjusted for credits from the sale of cogenerated electricity). CTL capacity is projected to be built only in the *AEO2003* high world oil price case.

State taxes on gasoline, diesel, jet fuel, M85, and E85 are assumed to increase with inflation, as has occurred historically. Federal taxes, which have increased sporadically in the past, are assumed to stay at 2001 nominal levels (a decline in real terms). Extension of the excise tax exemption for blending corn-based ethanol with gasoline, passed in the Federal Highway Bill of 1998, is incorporated in the projections. The bill extends the tax exemption through 2007 but reduces the current exemption of 53 cents per gallon by 1 cent per gallon in 2003 and 2005. It is assumed that the tax exemption will be extended beyond 2007 through 2025 at the nominal level of 51 cents per gallon (a decline in real terms).

High renewables case. The *high renewables case* uses more optimistic assumptions about renewable energy sources. The supply curve for cellulosic ethanol is shifted in each forecast year relative to the reference case, making larger quantities available at any given price than are available in the reference case.

Coal market assumptions

Productivity. Technological advances in the coal industry, such as improvements in coal haulage systems at underground mines, contribute to increases in productivity, as measured in average tons of coal per miner per hour. Productivity improvements are assumed to continue but to decline in magnitude over the forecast horizon. Different rates of improvement are developed, based on econometric estimates using historical data by region and by mine type (surface and underground). On a national basis, labor productivity is assumed to improve on average at a rate of 1.6 percent per year over the *AEO2003* forecast period, declining from an estimated annual improvement rate of 2.4 percent between 2001 and 2010 to a rate of 1.1 percent between 2010 and 2025. By comparison, productivity in the U.S. coal industry improved at an average rate of 7.1 percent per year between 1980 and

1990 and by 5.4 percent per year between 1990 and 2001.

Coal transportation costs. Transportation rates are escalated or de-escalated over the forecast period to reflect projected changes in input factor costs. The escalators used to adjust the rates year by year are generated endogenously from a regression model based on the current-year diesel price, employee wage cost index, price index for transportation equipment, and a producer time trend.

Coal exports. Coal exports are modeled as part of a linear program that provides annual forecasts of U.S. steam and coking coal exports in the context of world coal trade. The linear program determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands.

Mining cost cases. Two alternative mining cost cases examine the impacts of different labor productivity, labor cost, and equipment cost assumptions. The annual growth rates for productivity were increased and decreased by region and mine type, based on historical variations in labor productivity. The low and high mining cost cases were developed by adjusting the *AEO2003* reference case productivity path by one standard deviation, corresponding to adjustments in the annual growth rates of coal mine labor productivity by 2.0 percent for underground mines and 1.3 percent for surface mines. The resulting national average productivities in 2025 (in short tons per hour) were 14.28 in the *low mining cost case* and 7.08 in the *high mining cost case*, compared with 9.97 in the reference case. These are fully integrated cases, with feedback from the Macroeconomic Activity, International, supply, conversion, and end-use demand modules.

In the reference case, labor wage rates for coal mine production workers and equipment costs are assumed to remain constant in real terms over the forecast period. In the low and high mining cost cases, wages and equipment costs are assumed to decline and increase by 0.5 percent per year in real terms, respectively.

Notes

[*1*] Energy Information Administration, *Annual Energy Review 2001*, DOE/EIA-0384(2001) (Washington, DC, November 2002).

[*2*] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001*, DOE/EIA-0573(2001) (Washington, DC, December 2002).

[*3*] Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html.

[*4*] Maine has passed legislation that provides a goal of phasing out MTBE.

[*5*] Lawrence Berkeley Laboratory, *U.S. Residential Appliance Energy Efficiency: Present Status and Future Direction*; and U.S. Department of Energy, Office of Codes and Standards.

[*6*] Energy Information Administration, *A Look at Residential Energy Consumption in 1997*, DOE/EIA-0321(97) (Washington, DC, 1999).

[*7*] For additional information on green programs see web site www.energystar.gov.

[*8*] For further information see web site www.pathnet.org/about/about.html.

[*9*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*10*] National Energy Policy Act of 1992, P.L. 102-486, Title I, Subtitle C, Sections 122 and 124.

[*11*] Energy Information Administration, 1999 CBECS Public Use Data Files (January 2002), web site www.eia.doe.gov/emeu/cbecs/ and preliminary 1999 CBECS energy consumption and expenditure data (August 2002).

[*12*] A detailed discussion of the nonsampling and sampling errors for CBECS is provided in Energy Information Administration, *A Look at Commercial Buildings in 1995: Characteristics, Energy Consumption, and Energy Expenditures*, DOE/EIA-0625(95) (Washington, DC, October 1998), Appendix B, and at web site www.eia.doe.gov/emeu/cbecs/tech_errors_intro.html.

[*13*] High technology assumptions are based on Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Arthur D. Little, Inc., October 2001).

[*14*] For current DOE technology characterizations for photovoltaic systems see web site www.eren.doe.gov/power/pdfs/techchar.pdf.

[*15*] Energy Information Administration, *1998 Manufacturing Energy Consumption Survey*, web site www.eia.doe.gov/emeu/mecs/mecs98/datatables/contents.html.

[*16*] The data sources and methodology used to develop the nonmanufacturing portion of the Industrial Demand Module are described in Energy Information Administration, *Model Documentation Report: Industrial Sector Demand Module of the National Energy*

Modeling System, DOE/EIA-M064(2002) (Washington, DC, December 2001).

[*17*] National Energy Policy Act of 1992, P.L. 102-486, Title II, Subtitle C, Section 342.

[*18*] These assumptions are based in part on Energy Information Administration, *Industrial Model—Updates on Energy Use and Industrial Characteristics* (Arthur D. Little, Inc., September 2001).

[*19*] National Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[*20*] California Air Resources Board, Resolution 01-1 (January 25, 2001).

[*21*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Truck* (Energy and Environmental Analysis, September 2002).

[*22*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*23*] S. Davis, *Transportation Energy Databook No. 21*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 2001).

[*24*] D. Greene, *Energy Efficiency Improvement Potential of Commercial Aircraft to 2010*, ORNL-6622 (Oak Ridge, TN: Oak Ridge National Laboratory, June 1990), and Oak Ridge National Laboratory, Air Transportation Energy Use Model.

[*25*] Vehicle-miles traveled are the miles traveled yearly by light-duty vehicles.

[*26*] Ton-miles traveled are the miles traveled and their corresponding tonnage for freight modes, such as trucks, rail, air, and shipping.

[*27*] U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); Federal Highway Administration, *Highway Statistics 1998* (Washington, DC, November 1999); and S. Davis, *Transportation Energy Databook No. 19*, prepared for the Office of Transportation Technologies, U.S. Department of Energy (Oak Ridge, TN: Oak Ridge National Laboratory, September 1999).

[*28*] Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Truck* (Energy and Environmental Analysis, September 2002).

[*29*] A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[*30*] National Energy Policy Act of 1992, P.L. 102-486, Title XIX, Section 1916, and extended in Section 507 of the Tax Relief Extension Act of 1999 (Title V of the Ticket to Work and Work Incentives Improvement Act of 1999) and in the Job Creation and Worker Assistance Act of 2002, P.L. 107-147.

[*31*] Pacific Northwest Laboratory, *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States*, PNL-7789, prepared for the U.S. Department of Energy under Contract DE-AC06-76RLO 1830 (August 1991); and M.N. Schwartz, O.L. Elliott, and G.L. Gower, *Gridded State Maps of Wind Electric Potential. Proceedings, Wind Power 1992* (Seattle, WA, October 19-23, 1992).

[*32*] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, and Electric Power Research Institute, *Renewable Energy Technology Characterizations*, EPRI-TR-109496 (Washington, DC, December 1997), web site www.eren.doe.gov/power/techchar.html. Where projected cost or performance values for 2002 do not match EIA estimates for 2002, the EIA 2002 estimate is used, and the rate of cost decline through 2025 from the *Renewable Energy Technology Characterizations* is used to establish the 2025 target value.

[*33*] D.L. Goutier et al., *1995 National Assessment of the United States Oil and Gas Resources* (Washington, DC: U.S. Department of the Interior, U.S. Geological Survey, 1995); U.S. Department of the Interior, Minerals Management Service, *An Assessment of the Undiscovered Hydrocarbon Potential of the Nation's Outer Continental Shelf*, OCS Report MMS 96-0034 (Washington, DC, June 1997); U.S. Department of the Interior, Minerals Management Service, *2000 Assessment of the Conventionally Recoverable Hydrocarbon Resources of the Gulf of Mexico and Atlantic Outer Continental Shelf, as of January 1, 1999*, OCS Report MMS 2001-087 (New Orleans, LA, October 2001); National Petroleum Council, *Natural Gas: Meeting the Challenges of the Nation's Growing Natural Gas Demand* (Washington, DC, December 1999).

[*34*] Estimated from National Petroleum Council, *U.S. Petroleum Refining—Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993). Excludes operations and maintenance base costs before 1997.

[*35*] Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, San Diego, and Sacramento. Opt-in areas are in the following States: Connecticut, Delaware, Kentucky, Massachusetts, Maryland, Missouri, New Hampshire, New Jersey, New York, Rhode Island, Texas, Virginia, and the District of Columbia. Excludes areas that "opted-out" prior to June 1997.

[*36*] Arizona, California, Colorado, Connecticut, Iowa, Illinois, Indiana, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Nebraska, New York, Ohio, South Dakota, and Washington. The State of Maine has passed legislation that provides a goal of phasing out MTBE.

[*37*] Based on the methodology described in D. Gray and G. Tomlinson, *Coproduction: A Green Coal Technology*, Technical Report MP 2001-28 (Mitretek, March 2001).